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Evaluating the CO_2 emissions reduction potential and cost of power sector re-dispatch

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ABSTRACT

Prior studies of the U.S. electricity sector have recognized the potential to reduce carbon dioxide (CO_2) emissions by substituting generation from coal-fired units with generation from under-utilized and lower-emitting natural gas-fired units; in fact, this type of "re-dispatch" was invoked as one of the three building blocks used to set the emissions targets under the Environmental Protection Agency's Clean Power Plan. Despite the existence of surplus natural gas capacity in the U.S., power system operational constraints not often considered in power sector policy analyses, such as transmission congestion, generator ramping constraints, minimum generation constraints, planned and unplanned generator outages, and ancillary service requirements, could limit the potential and increase the cost of coal-to-gas re-dispatch. Using a highly detailed power system unit commitment and dispatch model, we estimate the maximum potential for re-dispatch in the Eastern Interconnection, which accounts for the majority of coal capacity and generation in the U.S. Under our reference assumptions, we find that maximizing coal-to-gas re-dispatch yields emissions reductions of 230 million metric tons (Mt), or 13% of power sector emissions in the Eastern Interconnection, with a corresponding average abatement cost of $15–$44 per metric ton of CO_2, depending on the assumed supply elasticity of natural gas.

1. Introduction

In the first decade of the 21st century, the U.S. power system experienced unprecedented growth in the installed capacity of natural gas combined cycle (NGCC) units. From 2000–2005 net additions of NGCC capacity totaled 138 gigawatts (GW), representing approximately a 270% increase in the installed capacity of NGCC units.[1] Over that same time period, growth in electricity consumption was relatively modest, increasing by only 7% (1.2% per year), and natural gas fuel prices for the electricity sector climbed from $4.25 per MMBtu in 2000 to $8.25 per MMBtu in 2005.[2] As a result, by the mid- to late-2000s, the boom in the installation of new NGCC units combined with limited growth in electricity demand and high natural gas prices resulted in a significant amount of under-utilized NGCC capacity - the average capacity factor for the NGCC fleet in 2005 was 35%.

More recently, advances in shale gas production have created an abundance of low-cost natural gas, which in turn has led to an associated increase in the utilization of NGCC plants. From 2005–2016 the average electricity sector price for natural gas fell from $8.21 per MMBtu to $2.99 per MMBtu, while the national average capacity factor for NGCCs increased from 35% to approximately 56% (ABB Velocity Suite).[3] Despite this increase in the utilization of NGCC plants, as of the end of 2016, there still remains a significant amount of unused NGCC capacity. The generation weighted average annual capacity factor of the 255 GW of existing NGCC capacity in 2015 and 2016 was 56% – well below the theoretical maximum. Except for required down time for maintenance, combined cycle units can be run at full capacity almost continuously, achieving annual capacity factors above 90% (Usune et al., 2011).[4] Thus, the potential exists in the U.S. to dramatically increase generation output from the existing NGCC fleet to displace generation from coal units. Given that coal-fired power plants, which historically account for the largest share of generation in the U.S.

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[1] ABB Velocity Suite, accessed 3/9/2016.

[2] Energy Information Administration (EIA) Electric Power Monthly, accessed May 2017.

[3] Historically, average capacity factors for NGCC plants have been highly correlated with natural gas prices — from 2005 to 2016 the simple correlation coefficient between the national average electric sector delivered natural gas price and the average NGCC capacity factor was 0.72.

[4] In the years 2014, 2015, and 2016 at least 46 NGCC (23 if excluding co-generation units) units operated at annual capacity factors above 80% and 14 (5 if excluding co-generation units) at above 90%, demonstrating the ability of NGCC plants to operate at very high capacity factors given appropriate conditions.

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(approximately 40% in 2014 and 33% in 2015), typically emit 2–2.5 times more CO_2 per megawatt-hour (MWh) than NGCC units,[5] re-dispatch from coal to NGCC units represents a substantial opportunity to reduce power sector CO_2 emissions.

Indeed, a number of analyses exploring the impacts of CO_2 emissions mitigation policies on the U.S. power sector find that coal-to-gas re-dispatch (sometimes referred to as fuel-switching) typically accounts for a substantial portion, if not the largest share, of the CO_2 abatement necessary to comply with the policies (Newell and Raimi, 2014; Paltsev et al., 2011; Ross and Murray, 2016; Logan et al., 2013; Bielen, 2015; Holladay and LaRiviere, 2015). Furthermore, the potential for abatement through re-dispatch has been considered in the determination of the stringency of CO_2 emission reduction policies. For example, in the development of the emissions reduction targets under the Clean Power Plan, the Environmental Protection Agency (EPA) carried out an analysis to assess the potential for abatement through alternative abatement measures. For coal-to-gas re-dispatch the EPA assumed that NGCC units could increase generation (to offset coal generation) up to the point where the NGCC units achieved a fleet-wide annual capacity factor of 70%.[6] However, the feasibility of achieving that level of utilization was questioned by some stakeholders, citing concerns about fuel and power transmission constraints, system reliability, and potential limitations due to existing emissions regulations.[7] Burtraw et al. (2014), although they do not explicitly challenge the feasibility of achieving a fleet-wide capacity factor of 70%, suggest that doing so could be relatively costly given the low efficiency of older NGCC plants.

The analysis presented here estimates the technical potential and associated cost for reducing power sector CO_2 emissions by substituting generation from *existing* coal units with generation from *existing* NGCC units in the Eastern Interconnection (EI).[8] We obtain our estimates by implementing PLEXOS, a commercially available bottom-up simulation model of generation and transmission operation. To the best of our knowledge, this is the first study to estimate the total CO_2 mitigation potential and cost of re-dispatch from coal to NGCC units in the U.S. using a security constrained unit commitment and economic dispatch (or production-cost) model. Use of a production-cost model allows for the consideration of power system constraints, such as transmission congestion and the availability of specific generating units, that may ultimately limit the potential for re-dispatch from coal to NGCC units. Furthermore, the model is generator-specific, allowing for the estimation of aggregated CO_2 mitigation potentials for any desired regionality, including states, balancing authorities, or utility service areas.

Our analysis is built around a base case, which simulates operation of the existing EI power system on a pure least-cost basis, and a maximum re-dispatch case, under which NGCC units are dispatched ahead of coal units. Our conclusions are based on direct comparison of the outcomes from the two cases, most notably emissions and cost. As a sensitivity analysis, we make our comparisons under different assumptions about the price of natural gas and the elasticity of supply for natural gas. This approach allows us to explore the *maximum* potential for re-dispatch between existing plants that could be achieved under a range of potential price and policy conditions. However, we do not estimate the expected level of re-dispatch under any particular policy nor do we consider the potential for new capacity or future retired capacity to alter the potential. Instead, our focus is on characterizing the full extent to which fuel-switching in the power sector can serve as a vehicle for short-run emissions reductions.[9]

Our results suggest that, even when accounting for key power system constraints, there is significant potential within the EI to displace generation from existing coal units with generation from existing NGCC units. We find that the fleet-wide NGCC capacity factor in the EI increases from 51% to 80% under our baseline reference and re-dispatch scenarios, respectively. This results in emissions reductions of 230 million metric tons (Mt), or 13%, with the largest reductions concentrated in the midwest, mid-atlantic, and southeast regions of the U.S. The corresponding average abatement cost ranges from $15–$44 per metric ton of CO_2 (tCO_2), depending on the assumed supply elasticity of natural gas. Furthermore we find that detailed power system operational constraints, including transmission congestion, ramp rate limits, minimum run times, and minimum stable generation levels, among other constraints, limit the potential for re-dispatch at large scales (over multi-state or market regions), but are secondary to capacity availability at the more local level.

Our paper is related to a number of prior studies that estimate the total potential for coal-to-gas re-dispatch (Gelman et al., 2014; Kaplan, 2010; Lafrancois, 2012). However, these prior analyses all use simple accounting frameworks to assess the potential amount of historical coal generation and associated CO_2 emissions that could have been offset by increasing generation from available NGCC capacity. As a result, none of these analyses estimate the cost of achieving the potential, nor do they fully address the technical feasibility, as they do not account for the suite of power system constraints and grid operation requirements that could limit the potential for re-dispatch, including transmission constraints, generator ramping constraints, peak load requirements, planned and unplanned generator outages, and ancillary service requirements. These constraints may prevent generation from seamlessly shifting from coal to NGCC units, even if excess NGCC capacity exists.[10] Of the three related studies, only Gelman et al. (2014) reports results at the sub-national level and therefore is the only study with which we can directly compare our results. Our estimated emissions reductions are between the values the authors estimate for scenarios in which re-dispatch is allowed between units falling within the same (1) independent system operator (ISO) region, and (2) interconnection region.

The remainder of the paper is structured as follows: Section 2 describes our model, analytic approach, and scenarios, Section 3 presents and discusses our results, and Section 4 synthesizes conclusions.

[5] This emissions rate comparison only includes burner-tip emissions - that is, the emissions resulting from the combustion of fuel. It is not a comparison of the life-cycle emissions associated with electricity generation from coal and NGCC units, and as a result, does not include emissions associated with upstream leakage from natural gas infrastructure. See Alvarez et al. (2012) and Brandt et al. (2014) for information on methane leakage from natural gas infrastructure.

[6] In order to set the targets, the EPA considered three “Building Blocks” that together comprise the “Best System of Emissions Reduction (BSER)”: increasing the operational efficiency of coal- or oil-fired steam units, shifting generation from coal units to lower-emitting gas units, and increased generation from renewable sources.

[7] See Comments of the Mississippi Public Service Commission, Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. Docket No. EPA-HQ-OAR-2013-0602 79 Fed. Reg. 34,830 (June 18, 2014), as well as Federal Register, Vol. 80, No. 205, p. 64728.

[8] We only consider re-dispatch to NGCCs, as opposed to natural gas combustion turbines (NGCTs), because the former represents a much more cost-effective abatement option. For example, using average heat rate data (from 2013), fuel prices (also from 2013), and fuel emissions factors from EIA, we calculate that the average abatement cost of re-dispatch from a coal plant to an NGCC plant is more than four times lower than re-dispatch from a coal plant to an NGCT plant (EIA, 2016, 2017b). Additionally, the mitigation potential for coal to NGCT re-dispatch will be limited by operational constraints, as NGCTs are able to provide quick-start capabilities that coal plants cannot. Therefore, the system operator may prefer to hold NGCT capacity in reserve, even if NGCTs are lower on the dispatch stack than coal.

[9] Over the long-run, the ability to add new NGCC capacity could further increase the potential (and lower the marginal cost) for coal-to-gas re-dispatch, while plant retirements (of either existing coal or NGCC capacity) could decrease the potential; our study does not consider these long-run opportunities or constraints.

[10] Lafrancois (2012) attempts to control for peak load requirements and generator outages using historical trends in plant operation, while both Gelman et al. (2014) and Kaplan (2010) attempt to control for transmission related constraints by limiting re-dispatch potential to coal and NGCC units within a specified maximum proximity of one another. Kaplan (2010) also provides an overview of the power system and natural gas supply system constraints that could potentially limit the mitigation potential, but does not provide an estimate of how these constraints could impact mitigation potential. None of these studies attempt to integrate the full suite of power system constraints into the analyses. Furthermore, Gelman et al. (2014) notes that additional research using generator dispatch models is necessary to refine and validate these more aggregated estimates.

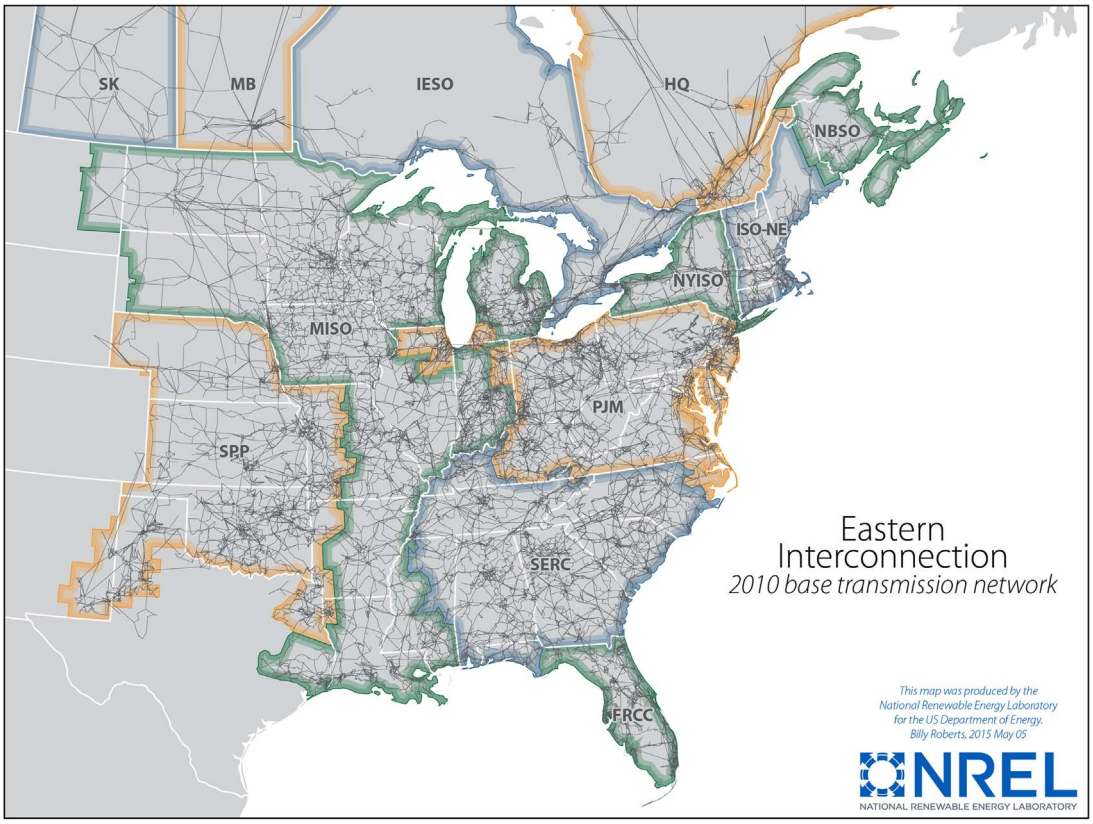

Fig. 1. Map of the Eastern Interconnection.

2. Methods

2.1. Model description

In this analysis we use the PLEXOS Integrated Energy Model, a commercially available production-cost model, to estimate the maximum potential and cost of reducing power sector CO_2 emissions through coal-to-gas re-dispatch.[11] The PLEXOS model is used by power sector industry participants—utilities and market operators[12]—to conduct generation and transmission system planning studies and resource adequacy assessments, as well as by academic researchers in studies examining a variety of topics, including integration of variable renewable generation and electricity storage resources (Bloom et al., 2016; Brouwer et al., 2016; Welsch et al., 2014; Lew et al., 2013; Edmunds et al., 2015),[13] impacts of electric vehicle charging (Foley et al., 2013), and impacts of environmental policies on grid operation (Wagner et al., 2014).

Given a specified power system, including generators, transmission lines, and loads, PLEXOS simulates the operation of each generator in order to meet load at least-cost while observing a large set of power system constraints. More specifically, the model simulates the commitment and dispatch of each generating unit in order to minimize the cost of meeting load in every time step modeled, taking into account transmission constraints (e.g. capacity and voltage), individual generator characteristics and constraints (e.g. minimum and maximum generation levels, ramp rate limits, minimum run time, minimum down time, start-up (or cold-start) costs, emissions rates, heat rates), fuel prices, emissions constraints (e.g. SO_x, NO_2, CO_2), and temporal and spatial variability in load.

Conceptually, unit commitment and dispatch refer to the decision variables required to simulate the operation of the power system. Unit commitment is the process of scheduling which generation units will be on (or available to generate) at a given time. This process accounts for the characteristics of each generator that may constrain how they can be committed, such as how quickly a generator can be turned on (start-up time), how long it must continue running once on or available to generate (minimum run time), and how long it must remain off once shut down (minimum down time). Unit commitment does not determine the level of output from each generator, but solely what subset of generators will be available to generate. Economic dispatch determines the optimal level at which each available generator should be operating. In this analysis, we model the operation of the power system over a full year at a 2-h resolution (4380 sequential 2-hourly time-steps per year).

Electricity grids within the U.S. are synchronous alternating current (AC) grids (and thus power flow is governed by AC physics). However, simulating AC power flow dynamics within a model is computationally intensive and is not feasible within the framework of a production cost model implemented over anything but a very small system. Therefore, PLEXOS uses a linearized decoupled approximation of AC power flow (often referred to as DC-optimal power flow).[14] This representation captures transmission capacity constraints–thermal limits and stability interface limits–and, as shown by Overbye et al. (2004), accurately predicts transmission congestion issues, our main concern with respect to re-dispatch. It does not capture the full suite of issues related to power flow such as reactive power and voltage stability, which are typically only examined in detailed reliability studies.

[11] PLEXOS is developed and licensed by http://energyexemplar.com/software/plexos-desktop-edition/Energy Exemplar.

[12] For example, by the California Independent System Operator (CAISO) and the Midwest Independent System Operator (MISO).

[13] A limited benchmarking analysis conducted by Bloom et al. (2016) demonstrated the capability of PLEXOS to closely replicate real-world dispatch over a modeled historical year.

[14] Production cost models implemented over any substantially sized system (state- to interconnection-scale) requires some form of approximation of power flow.

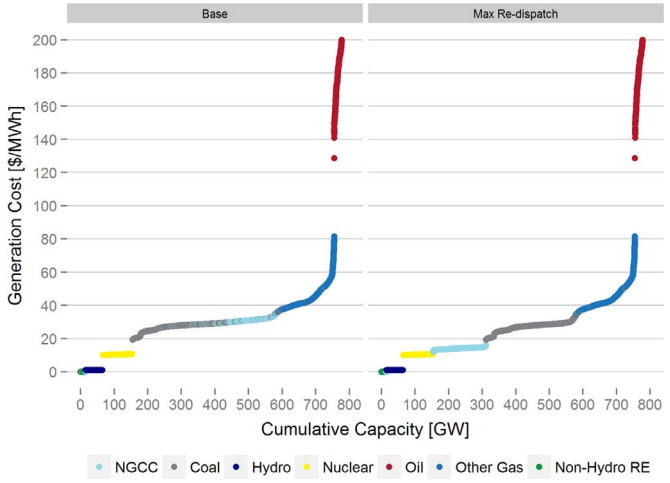

Fig. 2. Dispatch order under the Base and Re-dispatch cases; costs shown use August Base + $0 fuel prices.

2.2. Data

We perform our analysis for the Eastern Interconnection (EI), which is represented in Fig. 1.[15] The EI is one of three major AC electricity grids in the contiguous United States (the others being the Western Interconnection and the Texas Interconnection). It extends from the western great plains to the eastern coast of the U.S. and from south-central and eastern Canada to the Gulf Coast, and is comprised of an interconnected network of generators, transmission lines, buses, transformers, distribution systems, and electricity loads. The EI is the largest of the U.S. interconnections in terms of capacity and generation, accounting for 83% of national coal capacity and 80% of annual national coal generation. As a result, although this study does not consider the Western or Texas Interconnections, the potential to reduce emissions from the majority of coal plants in the U.S. is captured.

We detail the source of the generation and transmission system data, fuel price inputs, and electricity consumption data in the subsection below, and discuss concerns related to data inputs in the following subsection.

2.2.1 Data sources and vintage

The EI database used in our analysis was constructed by the National Renewable Energy Laboratory (NREL) for the Eastern Renewable Generation Integration Study (Bloom et al., 2016). This database was originally developed by Energy Exemplar and modified and improved by Bloom et al. (2016), and is based on the existing generation fleet and transmission infrastructure in the EI as of 2010. It represents over 7500 generating units making up 700 GW of generation capacity, approximately 60,000 transmission nodes, and a network of over 70,000 transmission lines spanning 459,000 miles that connect generators and nodes. Individual generator unit specifications include the minimum and maximum generation levels at which units can operate,[16] cold-start (or start-up) costs, maximum ramp rate, ramping costs, minimum run time, minimum down time, heat rates,[17] variable operations and maintenance costs, and annual hours of planned and unplanned outages.

Fuel price data for coal and natural gas units was obtained from the EIA Electric Power Monthly for 2013. Monthly, state-level, delivered power sector prices for coal and natural gas were used for all coal and natural gas-fired units. As a result, all natural gas-fired units within a state are specified the same fuel price for a given month. Similarly, all coal units within a state are specified the same fuel price for a given month.

Hourly load data for each utility service area in the EI was obtained from Ventyx for 2010.[18] The utility-level data was subsequently disaggregated to each of the demand nodes within each of the utility service areas.

2.2.2 Data limitations

This analysis focuses on the *short-run* potential to reduce emissions through re-dispatch from existing coal capacity to existing NGCC capacity. As such, we do not project or implement any changes to the generation or transmission system (to account for future additions or retirement of capacity), but rather we develop a model of the existing system and subsequently simulate the potential for re-dispatch with existing capacity only. Given the extensive amount of data required to parameterize a production cost model across a large geographic scale such as the EI, data for all parameters were not available for the current year. As a result, we used the most up-to-date data available and feasible for use in the study.

Generating unit and transmission data (including the full suite of unit parameters and characteristics) is based on the 2010 EI system, and load is derived from 2010 utility level consumption. Although net changes in total capacity were relatively small from 2010 to 2015 (12.5 GW, or less than 2% of total EI capacity), retired capacity was largely made up of coal units (net retirements of approximately 29 GW), while new capacity was largely made up of renewable (net additions of 19 GW) and NGCC capacity (net additions of 22 GW).[19] As a result, the system modeled has a greater amount of coal capacity and less NGCC capacity relative to the 2015 system. The greater amount of coal capacity on the modeled system will likely bias our estimates of the potential for re-dispatch upward, while the lesser amount of natural gas will likely bias the estimates downward. These effects will balance each other to some degree, but the overall directionality of the effect is difficult to predict.

2013 natural gas prices were selected as a proxy for expected gas prices in the near future. The annual average prices in 2013 are comparable to the average electric sector price forecast for 2020–2024 in the EIA's 2017 Annual Energy Outlook Reference case (EIA, 2017a). Forecasted fuel prices were not used because they are only available as annual averages at the census region level. The Electric Power Monthly data provide state-level monthly resolution.

2.3. Approach

In order to estimate the maximum potential and associated cost of

[15] The regions shown are the study regions and are based on a combination of the Regional Transmission Operator (RTO)/Independent System Operator (ISO) regions and the National Electricity Reliability Council (NERC) Regions. Colored lines indicate region boundaries and grey lines depict existing transmission lines with voltage rating over 69 kV. The U.S. regions depicted: Florida Reliability Coordinating Council (FRCC), Independent System Operator – New England (ISO-NE), Midwest Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), SERC Reliability Corporation (SERC), and Southwest Power Pool (SPP).

[16] Minimum generation levels are specified as a percent of the maximum generation level (or maximum capacity). For coal plants, minimum generation levels were set at 50% of maximum capacity for plants smaller than 600 MW and 30% of maximum capacity for plants larger than 600 MW. For NGCC plants, minimum generation was set at 50% of maximum capacity, irrespective of plant size.

[17] The heat rate of a unit is the amount of energy (fuel) required to generate a MWh of electricity. It typically changes with the utilization of the unit: when operating at lower levels of utilization, units have higher heat rates (lower efficiency). Changes in heat rates with changes in utilization are represented within the model by specifying piece-wise linear heat rate curves for each NGCC and coal unit. The heat rate curves are developed based on calculated heat rates at minimum, maximum, and average load from the EPA continuous emissions monitoring system (CEMS) data (http://www3.epa.gov/ttn/emc/cem.html).

[18] ABB Velocity Suite.

[19] While there have been limited changes in the capacity mix in the EI since 2010, there have been substantial changes in the generation mix since 2010 - namely the increased utilization of NGCC capacity and decreased utilization of coal, or re-dispatch. This effect, resulting from changing fuel prices, is captured within the modeling framework.

reducing CO_2 emissions through coal-to-gas re-dispatch, we examine the change in the emissions and cost between a base case (Base), which simulates least-cost operation of the EI under typical conditions, and a maximum re-dispatch case (Re-Dispatch), which simulates operation of the EI under a scenario in which re-dispatch from coal to NGCC units is maximized by dispatching NGCC units ahead of coal units. The difference in the CO_2 emissions between the cases indicates the maximum potential to reduce emissions through coal-to-gas re-dispatch, and the difference in total costs indicates the cost of achieving that level of emissions abatement.

Under the base case, the model solves for the least-cost dispatch of the fleet of EI generators given specified fuel prices. Under the re-dispatch case, the dispatch order is modified such that NGCC units are dispatched ahead of coal units irrespective of fuel prices. Within the modeling framework, this is achieved by providing a fuel subsidy to NGCC units such that the cost of generation from NGCC units, as seen by the model, is less than the cost of generation of coal units.[20] However, we only use this subsidy approach as a modeling tool to achieve the changes in dispatch. Cost results are based on cost accounting carried out ex-post of the modeling solution.

Fig. 2 shows the dispatch curves for generating units under the base (left panel) and re-dispatch (right panel) cases assuming August fuel prices from the Base + $0 and Re-dispatch + $0-E0 cases defined in the next section. Under the base case, the costs of generation from NGCC units overlap with those of coal units, but on average, are higher than those of coal units. As a result, coal units are generally dispatched ahead of NGCC units with the exception of higher efficiency, lower-cost NGCC units, which out-compete lower-efficiency, high-cost coal units. Under the re-dispatch case, the generation costs of NGCC units are shifted below those of coal units due to the natural gas fuel subsidy. However, this shift does not change the ordering of coal and NGCC units relative to other types of units (nuclear, wind, natural gas combustion turbine, or petroleum), nor does it limit the coal units from operating — coal units are still dispatched if there is insufficient NGCC capacity to meet load, or if the available NGCC capacity cannot be used to meet load due to transmission congestion or other operational constraints.[21] Furthermore, low-variable cost renewable capacity, including wind, solar, and hydro, as well as nuclear capacity are still dispatched ahead of NGCC capacity, as they are in the base case.

2.4. Scenarios

The dispatch of coal and NGCC generators in the base case is one of the key determinants of the potential to reduce emissions through coal to NGCC re-dispatch. The level of coal generation in the base case represents the maximum amount of coal generation that can be offset by increased generation from NGCC units, and the capacity factor of individual NGCC units represents the ability to increase generation at those units, both of which, in aggregate, dictate the level of re-dispatch possible. Within the model, the generation share or dispatch of coal and NGCC units is largely determined by the relative costs of generators. The cost of generation is, in turn, a function of an individual plant's heat rate and the cost of fuel. In PLEXOS each unit is assigned a heat rate curve which determines its heat rate at different levels of utilization. Therefore, within the model, given that each unit's heat rate curve is fixed, dispatch is largely determined by the relative prices of natural gas and coal fuels. As a result, fuel price assumptions, through their impact on coal and NGCC dispatch in the base case, will have a large impact on the potential to reduce CO_2 emissions through coal-to-gas re-dispatch. Furthermore, because the total cost of operating the system is predominantly comprised of the fuel consumption costs, the fuel price assumptions will also largely determine the cost of achieving those emissions reductions.

In order to examine how mitigation potential and costs change with alternative assumptions on natural gas price behavior, we run a suite of paired base case and re-dispatch case scenarios with alternative natural gas price inputs and inverse supply elasticities.[22] These sensitivities include pairs in which the natural gas price is assumed to be equivalent in the base and associated re-dispatch cases, as well as those in which the fuel price in the re-dispatch case is increased relative to the associated base case. The latter allows us to consider how the inverse elasticity of supply, or how increases in the fuel price resulting from increased consumption in the re-dispatch case, will impact cost of mitigation.

In total we analyze a set of fifteen scenarios – three separate base cases each paired with five separate re-dispatch cases (see Table 1). The base cases are simulated with three different fuel price inputs: 2013 natural gas prices, 2013 natural gas prices with a $2/MMBtu adder, and 2013 natural gas prices with a $4/MMBtu adder.[23] Because the specified fuel prices vary by month and region, the + $2 and + $4 cases increase the price of natural gas in each month and region by $2/MMBtu and $4/MMBtu, respectively. Higher natural gas prices in the base case increase the share of generation from coal and decrease the utilization of NGCC plants, which increases mitigation potential but also the cost of re-dispatch, as the increased use of natural gas is more costly the higher the price of the fuel. Table 1 illustrates our scenario-naming convention — which identifies the scenario as base or re-dispatch, the level of the natural gas adder, and the inverse elasticity (for re-dispatch cases) — and the average natural gas prices associated with each one.

For each base case, we examine five re-dispatch cases, each of which assumes a different inverse elasticity of natural gas supply. This parameter determines the change in the natural gas price between the base case and the re-dispatch case that results from the increased consumption of natural gas under the re-dispatch case. For example, assuming an inverse elasticity of 1.0 means that a 1% increase in the consumption of natural gas between the Base and Re-dispatch case results in a 1% increase in the price of natural gas. Alternatively, assuming an inverse elasticity of 0.5 means that a 1% increase in the consumption of natural gas between the Base and Re-dispatch case results in a 0.5% increase in the price of natural gas. A review of the supply elasticities for natural gas assumed in a wide range of models was conducted as part of the 26th Energy Modeling Forum (EMF-26). The study found the average inferred elasticity of supply across models to be between 0.7 and 2.4 depending on the year and assumed production from shale (Huntington, 2013). This implies a range of inverse elasticities of 0.4–1.4. For our analysis, we explore a range of inverse elasticities from 0 to 1.5.

The total production cost[24] and emissions of the base and re-dispatch case are evaluated for every scenario. Under the re-dispatch case,

[20] The cost of natural gas for natural gas combustion turbines (NGCTs) is unaltered.

[21] Other operational constraints that could limit the use of NGCC units (or reducing generation from coal units) include minimum down times or minimum generation constraints.

[22] In our re-dispatch scenarios, electric sector demand for natural gas is essentially fixed, since we force the model to dispatch NGCCs ahead of coal regardless of the relative fuel prices. Therefore, we use natural gas supply elasticities only to reflect different assumptions about how the price of natural gas might increase as we move out along the supply curve, which will in turn affect costs. An elasticity of supply is defined as the percent change in quantity supplied associated with a one percent change in price; however, because the change in quantity is pre-determined, it makes sense to focus on the *inverse* elasticity of supply instead. Formally, inverse supply elasticity $1/\varepsilon$ is defined as follows:

$$1/\varepsilon \equiv \frac{\Delta Price}{\Delta Quantity} \cdot \frac{Quantity}{Price}.$$

[23] Prices below the reference natural gas prices were not explored, thus our estimates represent an upper bound for the cost of re-dispatch; however we a simple regression approach to estimate the cost of abatement at reduced prices using results from the reference and sensitivity cases.

[24] We define total production cost as the sum of fuel costs, variable operations and maintenance costs, and startup costs.

Table 1
Scenarios.

Base scenario name	Re-Dispatch scenario name	Avg. NG Price, Base Case [$/MMbtu]	Avg. NG Price, Re-Dispatch Case [$/MMbtu]
Base + $0	Re-Dispatch + $0-E0	4.35	4.35
	Re-Dispatch + $0-E0.5		4.69
	Re-Dispatch + $0-E0.75		4.82
	Re-Dispatch + $0-E1.0		4.95
	Re-Dispatch + $0-E1.5		5.21
Base + $2	Re-Dispatch + $2-E0	6.44	6.44
	Re-Dispatch + $2-E0.5		7.27
	Re-Dispatch + $2-E0.75		7.69
	Re-Dispatch + $2-E1.0		8.11
	Re-Dispatch + $2-E1.5		8.95
Base + $4	Re-Dispatch + $4-E0	8.45	8.45
	Re-Dispatch + $4-E0.5		9.60
	Re-Dispatch + $4-E0.75		10.18
	Re-Dispatch + $4-E1.0		10.77
	Re-Dispatch + $4-E1.5		11.94

the total production cost will represent a subsidized cost as calculated by the model, since we implement an artificial subsidy for natural gas usage. We include this subsidy solely as a modeling mechanism to alter the dispatch order of coal and NGCC units under the re-dispatch case. However, we want to examine the cost of achieving the altered dispatch with the assumed natural gas price. As such, after the model solves, we recalculate the total production cost using the unsubsidized natural gas price instead of the subsidized price.[25] The difference in the total production cost between each base case and re-dispatch case pair represents the cost of maximizing re-dispatch from coal to NGCC units given assumed fuel prices. The difference in CO_2 emissions between cases is the maximum potential to reduce emissions through re-dispatch, and the ratio $\frac{\Delta Cost}{\Delta Emissions}$ is the average cost per ton of achieving those reductions.

Although we examine fifteen alternative re-dispatch cases with varying natural gas prices and supply elasticities, only one re-dispatch case needs to be run in PLEXOS. We use the subsidy mechanism to achieve the re-ordering of the coal and NGCC generation costs, and dispatch (and associated emissions) under the re-dispatch case is insensitive to changes in fuel costs. This is due to the fact that under each individual scenario, the magnitude of the subsidy for NGCC units is adjusted such that the generation costs of NGCC units are below that of coal units. The other re-dispatch scenarios are created by recalculating the production costs under the same model solution, as the differences in natural gas prices do impact the total production costs.

2.5. Limitations of approach

In addition to the data limitations identified above, there are a number of other important limitations associated with our approach. First, the boundary of this analysis is the power sector. Therefore, we do not model or capture the interaction effects with other sectors that consume significant amounts of natural gas, namely the residential buildings, commercial buildings, and industrial sectors.[26]

Second, we do not model constraints on the transmission and delivery of natural gas to NGCC units. Because the re-dispatch cases considered here result in large increases in power sector natural gas consumption, additional infrastructure development may be necessary to deliver the quantity of gas demanded under these scenarios, particularly in locations where transmission infrastructure is already at or near capacity. Therefore, the integrated cost of achieving emissions reductions through re-dispatch could be higher than our calculations suggest. However, a recent study examining the natural gas infrastructure requirements under future scenarios of increased power sector natural gas demand found that the incremental increase in interstate pipeline necessary to meet demand would be modest relative to historical additions, so these omitted costs would not likely change the results substantially (DOE, 2015).

Third, our modeling approach implicitly assumes that resources are co-optimized across the whole EI and does not consider long-term strategic behavior. Specifically, it does not include detailed information about bilateral contracts, self-scheduling, operational constraints related to AC power flow, and different operational practices across regions.

Fourth, we do not impose existing SO_x, NO_2, or CO_2 limits on the fleet. Given that our scenarios involve the substitution of generation from higher emitting coal units with generation from lower emitting NGCC units, emissions of these pollutants are almost certainly reduced, implying that emissions limitations are unlikely to impact results. However, boundaries for emissions regulations, particularly for NO_2 emissions, are specified regionally, and as a result, there could theoretically be a case when a decrease in generation from a coal plant just outside a regulatory boundary is offset by an increase in generation from an NGCC plant within the boundary. If that particular NGCC unit was already facing emissions constraints, it could be limited on the amount it could increase generation. Generally, given that the NO_2 emissions from coal units can be a factor of 10 greater than emissions from NGCC units, we expect this to have a insignificant impact on results.[27]

Finally, given sufficient computing power, PLEXOS is capable of modeling power system operation at up to a 5-min resolution; however, the computational requirements for modeling the system at this temporal resolution are significant and require very long runtimes. This analysis did not require such a high degree of temporal resolution, and so in order to reduce the problem size and maintain tractability we chose to run the model using a 2-h time step. In

[25] Total production cost is thus calculated as:.

$$\text{Total Production Cost} = \sum_{i,m} G_{i,m}{*}HR_i{*}P_{i,m} + G_{i,m}{*}C_i^{OM} + S_{i,m}{*}C_i^{UP}, \quad (1)$$

where $G_{i,m}$ is the total generation [MWh] for generator i and month m, HR_i is the unit heat rate [$\frac{MBtu}{MWh}$] for generator i, $P_{i,m}$ is the price [$\frac{\$}{MBtu}$] of fuel for generator i and month m, C_i^{OM} is the variable operations and maintenance cost [$\frac{\$}{MWh}$] for generator i, $S_{i,m}$ is the number of startups for generator i and month m, and C_i^{UP} is the startup cost [$\frac{\$}{start}$] for generator i.

[26] Presumably, natural gas price increases resulting from a significant increase in power sector demand would result in less consumption in other sectors, which in turn would put downward pressure on gas prices.

[27] The average NO_2 emissions rate for coal and NGCC plants in the U.S. in 2014 was 1.89 lbs per MWh and 0.33 lbs per MWh, respectively. See EPA's Emissions & Generation Resource Integrated Database (eGRID).

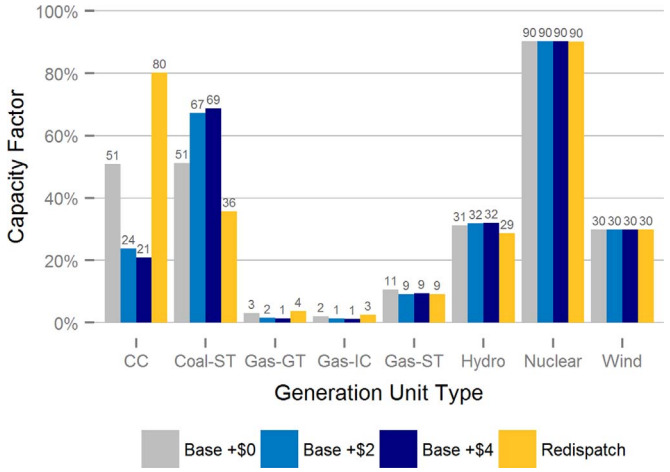

Fig. 3. Fleet-wide generation weighted average annual capacity factor by technology.

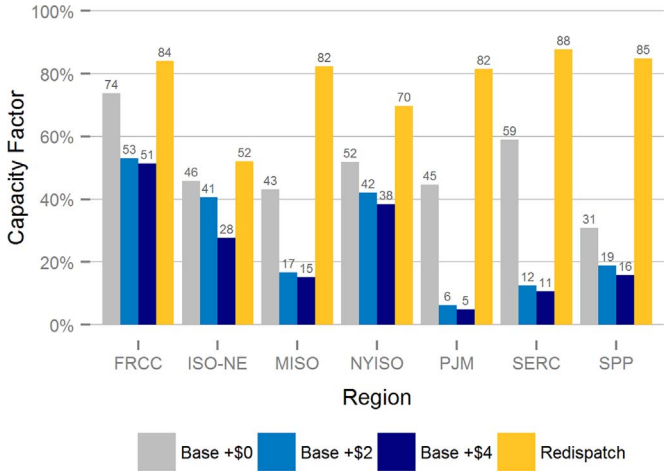

Fig. 4. Generation weighted average annual NGCC capacity factors by region.

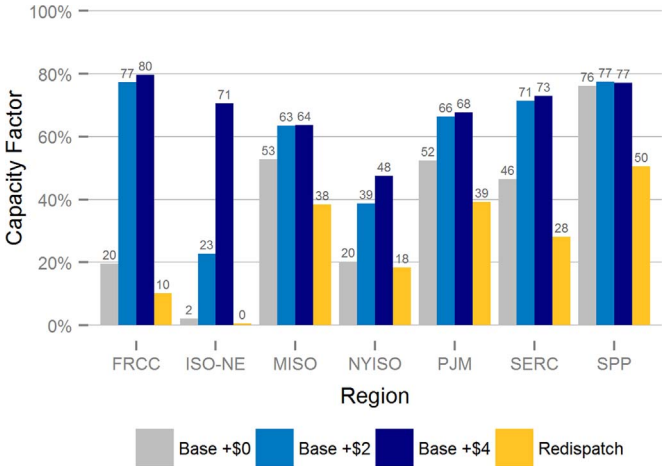

Fig. 5. Generation weighted average annual coal-steam capacity factors by region.

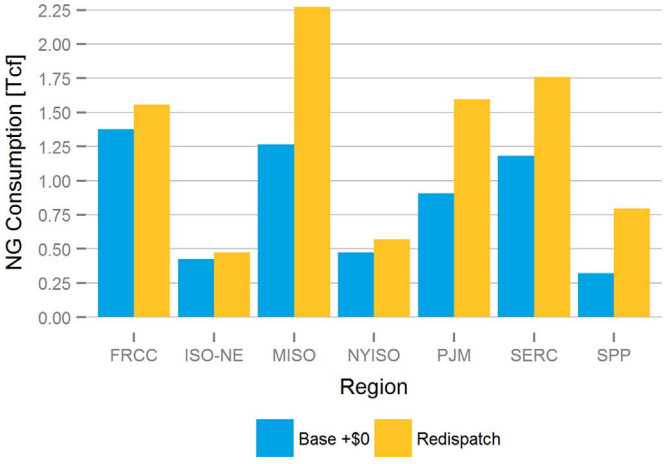

Fig. 6. Change in natural gas usage by region.

addition, we examined a suite of test cases in which we simulated dispatch over 2 alternative weeks at a 1-h resolution and found negligible impact on the results. Although we have not run explicit tests at sub-hourly time-steps, we do not expect results to differ from our core scenarios.

3. Results and discussion

In this section, we present our results on the potential and cost of coal-to-gas re-dispatch in the EI for the scenarios described in Section 2.4. Because natural gas prices do not affect the dispatch of coal and NGCC units under the re-dispatch cases (but do affect dispatch in the base cases), we present the dispatch and emissions results from the three base cases (Base + $0, Base + $2, Base + $4) and the Re-Dispatch + $0-E0 case. Production cost and abatement cost results are shown for all scenarios.

3.1. Dispatch, fuel use, and emissions

3.1.1. Dispatch

Fig. 3 shows the fleet-wide annual capacity factor by generator type for the three base cases and the Re-Dispatch + $0-E0 case.[28] The utilization of coal and NGCC plants in the base case is roughly equivalent on a capacity factor basis: both coal and NGCC units are operated at roughly 50% of their capacity. However, given that coal accounts for significantly more capacity (285 GW versus 158 GW of NGCC capacity), total generation from coal units (1281 TWh) significantly exceeds total generation from NGCC plants (702 TWh). When natural gas prices are increased in the base case, the utilization of NGCCs declines sharply and is offset by increased coal plant utilization. Increasing the state specific monthly natural gas prices by $2/MMBtu results in a decrease in the annual average capacity factor of NGCCs of almost 30 percentage points and an increase in the capacity factor of coal units of 16 percentage points. Further increases in the price of natural gas have little effect on the utilization of coal and NGCC units, as some regions do not have sufficient coal capacity in order to serve load, and thus NGCC units must be run despite the relatively high fuel price compared to coal.[29] Under the re-dispatch case, we observe a sharp increase in the utilization of the NGCC units. The annual average capacity factor for all NGCC units in the EI climbs to 80%, while the capacity factor of coal units falls to 36%.

[28] Fossil technologies are abbreviated as follows: Natural Gas Combined Cycle (CC), Coal Steam (Coal-ST), Natural Gas Turbine (Gas-GT), Natural Gas Internal Combustion (Gas-IC) and Natural Gas Steam or Simple Cycle (Gas-St).

[29] Although we observe significant differences in the dispatch of coal and NGCC units across the base cases, utilization of other generator types is largely unaffected. Given that these technologies have either significantly lower (including hydro, nuclear, and wind generators) or higher (natural gas combustion turbines, internal combustion, gas-steam) costs of generation than coal and NGCC units (see Fig. 2), their dispatch order relative to NGCC units is largely unaffected.

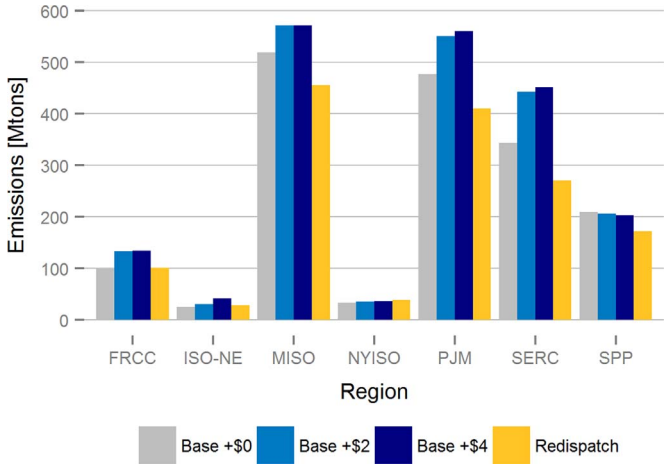

Fig. 7. CO_2 Emissions by region.

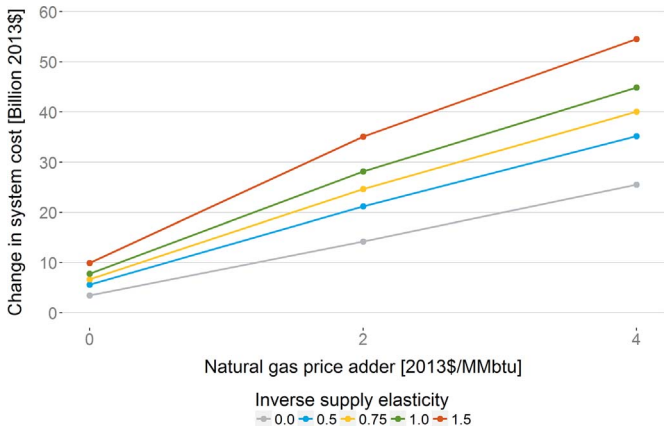

Fig. 8. Costs of Re-dispatch.

Figs. 4 and 5 illustrate the average annual capacity factors of NGCC and coal units, respectively, on a regional basis.[30] Under the base cases, we find that the EI-wide changes in capacity factors of coal and NGCC units resulting from increases in the natural gas price are primarily driven by the responses in FRCC, MISO, PJM, SERC, and SPP. ISO-NE and NYISO are less sensitive to the changes in natural gas prices. This is due to the fact that these regions have relatively little coal capacity, and thus they must rely on natural gas for generation, even under scenarios in which natural gas prices are relatively high.

Under the Re-Dispatch + $0-E0 case, the average annual capacity factor of NGCC units climbs to well above 80% in FRCC, MISO, NYISO, PJM, and SPP, and approaches 90% in SERC, while capacity factors of NGCCs in ISO-NE and NYISO climb to 52% and 70% respectively. The capacity factors achieved in ISO-NE and NYISO are lower relative to other regions because, as noted above, both ISO-NE and NYISO have very little existing coal capacity (≈ 4 GW in ISO-NE and ≈ 3 GW in NYISO) and, therefore, a more limited potential to offset coal generation within the region. Under the Re-Dispatch + $0-E0 case, coal units in ISO-NE are not dispatched at all (the capacity factor of coal units is 0% — see Fig. 5). However, because these units only account for a small amount of generation in the base cases, the associated increase in utilization of NGCC plants is limited. In NYISO, coal continues to generate under the Re-Dispatch + $0-E0 case despite NGCC units operating at only 70%. This occurs because during times of peak load, the existing NGCC capacity is not sufficient to meet demand (i.e., it is operating at 100% capacity factor), and thus some coal capacity must be brought online to serve load.

Despite the fact that there is limited coal generation within NYISO and ISO-NE that could be offset, the utilization of NGCCs could, in theory, be increased in order to offset coal generation in neighboring regions (PJM). The fact that we do not observe this (coal capacity factors in PJM remain at almost 40% under the Re-dispatch case) indicates that operational constraints including transmission congestion and mismatch between NGCC availability and coal generation are limiting the use of NYISO and ISO-NE NGCC capacity to offset PJM coal generation (or coal generation in other regions). This result identifies the importance of considering these operational constraints in estimating the potential for changes in dispatch.

3.1.2. Fuel usage

Natural gas fuel usage increases significantly as the utilization of NGCC units increases — we show the regional results in Fig. 6. Across the EI, total natural gas consumption increases from approximately 6.0 trillion cubic feet (Tcf) in the Base + $0 case to 9.0 Tcf in the Re-Dispatch + $0-E0 case. This represents a 50% increase in total EI power sector gas consumption. On a regional basis, MISO and PJM exhibit the largest absolute increases in natural gas consumption (1.0 and 0.8 Tcf, respectively), while SPP experiences the largest relative increase in natural gas usage (nearly threefold).

These levels of natural gas consumption are well above current levels of power sector consumption of natural gas in the EI. As a result, the feasibility of delivering this quantity of natural gas to NGCC units should be examined in greater detail. However, DOE (2015) explores the natural gas transmission and distribution infrastructure implications of similar levels of increased power sector demand for natural gas and finds that these levels of consumption can be accommodated with relatively modest changes to the system. Specifically, the study examined a scenario in which natural gas demand in the power sector increased by 46% on a national basis.[31] Despite this relatively large increase in power sector natural gas demand, the study concluded that this would only result in a 10% increase in natural gas transmission capacity additions above the reference case additions between present day and 2030. This limited impact on transmission infrastructure investment is largely due to the ability to increase utilization of existing pipelines.

3.1.3. Emissions

Fig. 7 illustrates regional CO_2 emissions. Under the Base + $0 case, interconnection-wide CO_2 emissions total 1710 million metric tons (Mt). Under cases with higher natural gas prices, decreased utilization of NGCC units and increased generation from coal plants lead to significantly higher emissions – under the Base + $2 and Base + $4 cases, emissions total 1970 Mt and 2000 Mt, respectively. The national increases in emissions are driven by large emissions increases in FRCC, MISO, PJM, and SERC.

Results from the Re-Dispatch cases indicate that re-dispatch from coal to NGCC units has the potential to significantly reduce power sector CO_2 emissions. Total emissions under the Re-Dispatch case are 1480 Mt, which equates to a 230 Mt (13%) reduction from the Base + $0 case, a 490 Mt (25%) from the Base + $2, and a 520 Mt (26%) reduction in emissions from the Base + $4 case. The emissions reductions from re-dispatch are concentrated in the coal-dominated regions (MISO, PJM, SERC, and SPP). In fact, in regions with limited coal capacity (FRCC, ISO-NE, and NYISO) CO_2 emissions slightly increase relative to the Base + $0 case (Fig. 7) because the utilization of NGCC units in these regions increases in order to allow reduced generation from coal units

[30] Regions are abbreviated as follows: Florida Reliability Coordinating Council (FRCC), Independent System Operator - New England (ISO-NE), Midwest Independent System Operator (MISO), New York Independent System Operator (NYISO), PJM Interconnection (PJM), SERC Reliability Corporation (SERC), and Southwest Power Pool (SPP).

[31] For comparison, the Re-dispatch + $0 scenarios represent a 50% increase in EI-wide natural gas usage relative to the Base + $0 cases.

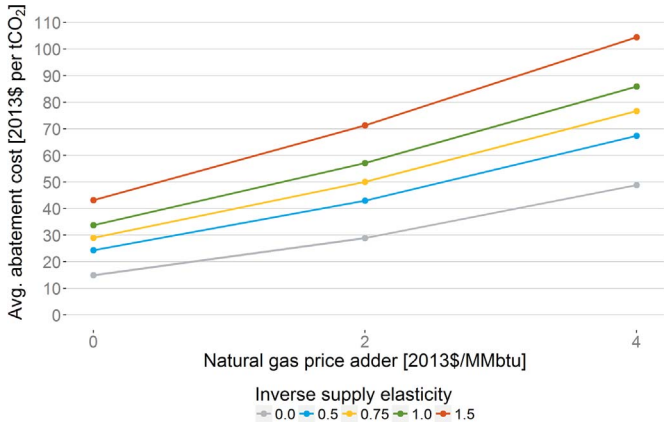

Fig. 9. Average cost of CO_2 abatement through Re-dispatch.

in neighboring regions. This arbitrage leads to a decrease in system-wide emissions, but a slight increase in emissions in regions with limited coal capacity and relatively high NGCC capacity. Under the Re-Dispatch + $0-E0 case, these regions either export more power or import less, depending on whether they are net importers or exporters in the base cases.

We can compare our emissions results to the results from Gelman et al. (2014). Gelman et al. (2014) develop alternative estimates of the potential for emissions reductions based on limiting re-dispatch to coal and NGCC units located within a specified maximum proximity of one another. These restrictions are intended to capture the limitations that transmission constraints or congestion could have on re-dispatch. They estimate the emissions reductions in the EI of 198.2 Mt when re-dispatch is restricted to plants falling within the same independent system operator (ISO) region and 262.7 Mt when re-dispatch is allowed to occur between any plants falling within the same interconnection level; our estimate of 230 Mt is between these values.[32] This suggests that restricting re-dispatch to the ISO level in an accounting framework might exclude possible fuel-switching opportunities, while restricting to the interconnection level allows for re-dispatch that violates constraints on transmission and the supply-demand balance.

3.2. Costs

3.2.1. Production costs

Fig. 8 illustrates the change in total production costs associated with re-dispatch for each combination of natural gas price and elasticity assumptions. The positive slope of each line in the figure illustrates that as natural gas prices increase from the reference prices, the cost of re-dispatch, defined as the change in production cost within each scenario, increases as well. Two effects drive this result. First, the per-MWh cost of additional NGCC usage (in lieu of lower cost coal units) is greater with more expensive natural gas. Second, as the price of natural gas increases, the amount of natural gas used in the base case is reduced, which increases the magnitude of the change in natural gas usage between the base and re-dispatch cases.[33] Thus, when the price of natural gas increases, the cost of re-dispatch increases because natural gas is more costly, and the change in usage of natural gas is greater.

Comparing across the scenarios with alternative elasticity assumptions, we find that the cost of re-dispatch is lowest when the inverse supply elasticity of natural gas is assumed to be zero (i.e. price is unresponsive to the amount of natural gas supplied), and increases with the inverse elasticity parameter. When the inverse elasticity is assumed to be zero, the price of natural gas is the same in both the base and re-dispatch cases, and thus the cost of re-dispatch largely reflects the baseline price differential between coal and natural gas and the change in usage of the two fuels. However, if supply is assumed to exhibit some level of elasticity, then the price paid by generators for natural gas increases in the re-dispatch (but not base) cases, creating an additional cost of maximizing re-dispatch beyond the baseline price differential and fuel usage changes.

Quantitatively, we find that maximizing re-dispatch increases the total production cost by 5–29% in the zero-inverse elasticity scenarios, depending on the price of natural gas. Assuming a positive inverse supply elasticity significantly increases the cost of re-dispatch, particularly in the + $4 adder scenarios, which assume almost a two-fold increase in natural gas prices relative to the reference 2013-based prices.

As mentioned earlier, one key consideration with respect to the non-zero elasticity results is that our analysis assumes that natural gas consumption in the rest of the economy – in the industrial, transportation, and residential and commercial buildings sectors – remains constant across all scenarios. The changes in natural gas prices between Base and Re-dispatch cases are calculated solely based on the change in consumption within the power sector alone (and the assumed inverse elasticity of supply). In reality, increases in power sector consumption of natural gas (and associated increases in natural gas prices) would likely drive decreases in consumption in other sectors, mitigating the overall increase in natural gas prices. Smaller increases in natural gas prices between the Base and Re-dispatch pairs would lead to lower overall changes in production costs.

Similarly, we do not consider the potential change in coal prices between the Base and Re-dispatch cases. Given the reduction in coal use between the Base and Re-dispatch cases, coal prices would likely fall slightly, further reducing the production costs in the Re-dispatch cases and the associated change in costs between Base and Re-dispatch cases.

3.2.2. Cost of abatement through re-dispatch

Fig. 9 shows the average CO_2 abatement cost through re-dispatch for all scenarios. Under our base fuel price assumptions (+ $0 price adder), average abatement costs range from $15 per tCO_2 to $43 per tCO_2, depending on the inverse elasticity of supply. Thus, under the base case, the total potential for abatement through re-dispatch can be achieved at an average cost ranging from well below to approximately equivalent to the central value of the Social Cost of Carbon ($42 per tCO_2 in 2020).[34] Under cases with higher assumed prices of natural gas, the average cost of abatement increases substantially: $29 per tCO_2 to $71 per tCO_2 and $49 per tCO_2 to $104 per tCO_2 for the Base + $2 and Base + $4 cases, respectively, depending on the assumed elasticity.

There are a few important caveats for interpreting our abatement cost results. First, abatement costs at the high end of the range assume natural gas prices of almost $12/MMBtu in the re-dispatch case on an annual average basis, a figure that significantly exceeds historical power sector annual average natural gas prices. In fact, U.S. power

[32] To create the most valid comparison, we obtained unpublished results from the authors for scenarios in which NGCCs achieve an 80% capacity factor, which matches our average re-dispatch capacity factor. Moreover, the baseline in Gelman et al. (2014) most closely reflects our Base + $0 case, so we use our estimate of 230 Mt.

[33] Recall that dispatch under the re-dispatch cases is unaffected by the price of natural gas, and therefore natural gas usage in those cases is constant across all fuel price sensitivities.

[34] The Social Cost of Carbon (SCC) is an estimate of the climate change related costs or damages associated with an incremental increase in carbon emissions. The SCC was developed to allow policy makers or government agencies to incorporate the social benefits of CO_2 emissions reductions into cost-benefit analyses. The SCC report (https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf see the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis, Under Executive Order 12,866, August 2016) provides a range of estimates for the SCC based on a range of discount rates used to calculate the damages in future years. The "central value" assumes a discount rate of 3%. As of the writing of this report, the SCC is no longer required to be used by federal agencies in the evaluation of the costs and benefits of emissions regulations.

sector delivered natural gas prices reached a maximum in 2008 at approximately $9/MMbtu. Thus, the abatement costs from the high range reported may not realistically be observed in practice. If we limit our analysis to scenarios in which natural gas prices do not exceed the historical high natural gas prices, we estimate a range of average abatement costs of $15 per tCO_2 to $71 per tCO_2.

Second, as noted above, our analysis assumes that natural gas consumption outside of the power sector remains constant across all scenarios, which exaggerates the effects of the increases in power sector consumption on natural gas prices, leading to an upward bias on the change in production costs between Base and Re-dispatch cases and the associated costs of abatement. Similarly, we do not consider the effects of changes in coal consumption on coal prices, which also creates an upward bias, albeit likely minor, on our estimates of cost of abatement.

Third, the abatement costs reported are the average cost of *maximizing* the potential for abatement through re-dispatch, and as such represent an upper-bound estimate of the cost of achieving the total amount of abatement possible through re-dispatch. The average cost of abatement of achieving emissions reductions short of the *maximum* level achieved in each of the scenarios explored would be less than the reported average abatement cost. Thus, based on these three points, our estimates can be viewed as an upper-bound on the average price and associated cost of re-dispatch.

Finally, our sensitivities on the base gas prices – the +$2 and +$4 scenarios – represent increases relative to forecasted reference-case prices from the AEO (EIA, 2017a). We do not explore potential decreases in prices below that level. As a result, our ranges within each elasticity category are truncated at the low-end. Additional modeling would be required for verification, but, extrapolating the relationship between gas prices and average abatement demonstrates that a decrease in gas prices of $2 from the reference level would produce average abatement costs on the order of $7 per tCO_2 if gas supply is perfectly elastic.

4. Conclusions and policy implications

This analysis uses a production cost model to estimate the maximum potential and cost of reducing power sector CO_2 emissions through coal to NGCC re-dispatch in the Eastern Interconnection. We simulate a set of scenarios which allow us to quantify the potential for re-dispatch and the associated cost under a range of natural gas price conditions. We find that as a result of excess NGCC capacity in the Eastern Interconnection, there is a substantial opportunity to reduce emissions through coal-to-gas re-dispatch under the full range of natural gas price conditions explored. We estimate that maximizing re-dispatch would achieve a reduction of approximately 230 million metric tons of CO_2 per year in the Eastern Interconnection, representing a 13% decrease in EI emissions below our reference (base) scenario. For states falling within the Eastern Interconnection, re-dispatch of this magnitude could account for approximately 60% of the CO_2 reductions necessary to comply with the mass-based targets under the Clean Power Plan.

This reduction is achieved by increasing the utilization of NGCC units from an average capacity factor of approximately 50% to over 80% on an annual basis. NGCC units in many regions, specifically in regions with sufficient existing coal generation, achieve capacity factors well above 80% with some approaching 90%, confirming that the 70% capacity factor assumed in setting the Clean Power Plan targets to be achievable, even when consider operational constraints. The high capacity factor of NGCC units achieved demonstrates that operational constraints, including transmission congestion, ramping constraints, and minimum run times (and down times), appear to be secondary in significance to capacity availability. However, these power system operational constraints do limit re-dispatch over large regions, such as across multiple states or at the Interconnection level. As a result, in our maximum re-dispatch cases some NGCC units remain underutilized, despite the fact that coal units still account for a significant portion of generation (36%).

Depending on how the price of natural gas changes with increased power sector consumption of natural gas, the average cost of achieving the total potential for abatement through coal-to-gas re-dispatch ranges from $15–$43 per tCO_2 under the Base-case gas price assumptions - similar to or below the Social Cost of Carbon. Sensitivities exploring re-dispatch under higher natural gas prices result in substantially higher costs, but also significantly greater emissions reduction potential due to the increased coal dispatch in the base case.

Our analysis demonstrates that coal-to-gas re-dispatch in the Eastern Interconnection is a large potential source of CO_2 abatement achievable at cost similar to or less than the SCC. Thus, this opportunity for abatement is important to consider when identifying pathways to reduced emissions in the power sector or in setting emission reduction targets. However, as noted earlier, our analysis solely examines the direct combustion emissions implications of re-dispatch. Changes in upstream leakage of methane from the natural gas supply chain associated with increased natural gas consumption could have important implications for the net effects of re-dispatch on total economy-wide emissions.

Finally, although this analysis uses a production cost model to control for power system constraints which may limit the opportunity for re-dispatch, constraints in the natural gas infrastructure are not considered and could, in principal, further limit the ability to re-dispatch. These considerations warrant further research with a co-optimized power sector-natural gas infrastructure model, yet prior analyses indicate that natural gas transmission infrastructure would have limited impact on the potential or cost of re-dispatch.

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